G-010/GR-90-678 FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Darrel L. Peterson	Chair
Cynthia A. Kitlinski	Commissioner
Dee Knaak	Commissioner
Norma McKanna	Commissioner
Patrice M. Vick	Commissioner

In the Matter of the Application of Midwest Gas, a Division of Iowa Public Service Company, for Authority to Change Its Schedule of Gas Rates for Retail Customers within the State of Minnesota	ISSUE DATE: July 12, 1991 DOCKET NO. G-010/GR-90-678 FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER

PROCEDURAL HISTORY

I. INITIAL PROCEEDINGS

On September 14, 1990, Midwest Gas (Midwest or the Company) filed a petition seeking a general rate increase of $2,590,902, or 5.7%, effective November 13, 1990.

On October 16, 1990, the Commission accepted the filing, suspended the proposed rates, and ordered contested case proceedings under Minn. Stat. § 216B.16, subd. 1 (1990). The Office of Administrative Hearings assigned Administrative Law Judge Allen E. Giles to the case.

On November 9, 1990, the Commission set interim rates under Minn. Stat. § 216B.16, subd. 3 (1990). Interim rates were authorized as of November 13, 1990, and were set at a level allowing an additional $1,210,773 in annual revenues.

The Administrative Law Judge (ALJ) held a Prehearing Conference on November 15, 1990. There the parties and the ALJ identified the major issues, established procedural guidelines, and set timetables. On November 26, 1990, the ALJ issued a Prehearing Order establishing a schedule and setting various procedures.

II. PARTIES AND REPRESENTATIVES

A. Intervenors

The following parties filed petitions to intervene in the case. The ALJ granted all petitions.

Minnesota Department of Public Service (the Department), represented by Scott Wilensky, Special Assistant Attorney General, 1100 Bremer Tower, Seventh Place and Minnesota Street, St. Paul, Minnesota 55101.

Residential Utilities Division of the Office of the Attorney General (RUD-OAG), represented by Julia E. Anderson and Gary R. Cunningham, Special Assistant Attorneys General, 340 Bremer Tower, Seventh Place and Minnesota Street, St. Paul, Minnesota 55101.

Minnesota Senior Federation (the Seniors), represented by Elmer W. Scott and Dr. Kenneth M. Zapp, Iris Park Place, 1885 University Avenue, Suite 171, St. Paul, Minnesota 55104.

B. The Company

The Company was represented by Steven R. Weiss and J. Gregory Porter, Midwest Gas, 401 Douglas Street, Box 778, Sioux City, Iowa 55102.

III. PUBLIC HEARINGS AND TESTIMONY

The ALJ held public hearings to receive comments and questions from non-intervening ratepayers. The dates and locations of these hearings are listed below, followed by the number of persons who attended each hearing.

February 6, 1991	7:00 P.M.	Cambridge	0
February 7, 1991	1:30 P.M.	Coon Rapids	3
February 7, 1991	7:00 P.M.	Coon Rapids	4

Commissioners Norma McKanna and Patrice Vick were present at the Cambridge public hearing. Commissioner Cynthia Kitlinski was present at the Coon Rapids hearings.

In all, three members of the public spoke. A small business ratepayer expressed his belief that a general rate increase should not be implemented during a business slowdown such as we are experiencing. Two senior citizens stated that senior citizens on fixed incomes would be especially hard hit by a rate increase.

No members of the public contacted the Commission by telephone or letter to comment on the proposed rate increase.

IV. EVIDENTIARY HEARINGS

The ALJ held evidentiary hearings in St. Paul on February 19, 21 and 25, 1991. The ALJ closed the record on April 23, 1991.

V. PROCEEDINGS BEFORE THE COMMISSION

The ALJ filed his report on May 13, 1991. On June 10 and 11, 1991, the Commission heard oral argument. Upon review of the entire record of this proceeding, the Commission makes the following Findings, Conclusions, and Order.

FINDINGS AND CONCLUSIONS

VI. JURISDICTION

The Commission has general jurisdiction over the Company under Minn. Stat. §§ 216B.01 and .02 (1990). The Commission has specific jurisdiction over rate changes under Minn. Stat. § 216B.16 (1990).

The case was properly referred to the Office of Administrative Hearings under Minn. Stat. §§ 14.48-14.62 (1990) and Minn. Rules, Part 1400.0200 et seq.

VII. FURTHER ADMINISTRATIVE REVIEW

Under Minn. Rules, Part 7830.4100, any petition for rehearing, reconsideration, or other post-decision relief must be filed within 20 days of the date of this Order. Such petitions must be filed with the Executive Secretary of the Commission, must specifically set forth the grounds relied upon and errors claimed, and must be served on all parties. The filing should include an original, 13 copies, and proof of service on all parties.

Adverse parties have ten days from the date of service of the petition to file answers. Answers must be filed with the Executive Secretary of the Commission and must include an original, 13 copies, and proof of service on all parties. Replies are not permitted.

The Commission, in its discretion, may grant oral argument on the petition or decide the petition without oral argument.

Under Minn. Stat. § 216B.27, subd. 3 (1990), no Order of the Commission shall become effective while a petition for rehearing is pending or until either of the following: ten days after the petition for rehearing is denied or ten days after the Commission has announced its final determination on rehearing, unless the Commission otherwise orders.

Any petition for rehearing not granted within 20 days of filing is deemed denied. Minn. Stat. § 216B.27, subd. 4 (1990).

VIII. MIDWEST GAS

Midwest Gas is a retail distributor of natural gas and related transportation services operating in the states of Minnesota, Iowa, Nebraska and South Dakota. The Company is an operating division of Iowa Public Service (IPS), an electric and natural gas distribution utility. IPS in turn is a subsidiary of Midwest Resources, Inc. (MRI), formerly known as Midwest Energy Company.
The immediate predecessor to Midwest Gas in Minnesota was North Central Public Service Company (North Central). In 1986, Midwest Energy Company purchased the common stock of North Central's

parent, Donovan Companies, Inc. Midwest Energy Company then transferred all of North Central's assets to IPS. At that time North Central became a division of IPS; since then, North Central has become part of Midwest Gas.

Midwest Gas serves 347,000 gas customers in 208 communities located in western, central, and north central Iowa, 38 suburban communities north of Minneapolis and St. Paul, Minnesota, eight southeast South Dakota communities and three northeast Nebraska communities. The present rate case involves only Midwest's gas operations in Minnesota.

IX. BURDEN OF PROOF

Minn. Stat. § 216B.16, subd. 4 (1990) states: "The burden of proof to show that the rate change is just and reasonable shall be upon the public utility seeking the change."

The Minnesota Supreme Court has articulated standards for the burden of proof in rate cases. In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Service in Minnesota, 416 N.W.2d 719 (Minn. 1987). In the Northern States Power case the Court divided the ratemaking function of the Commission into quasi-judicial and legislative aspects. The Commission acts in a quasi-judicial mode when it determines the validity of facts presented. Just as in a civil case, the burden of proof is on the utility to prove the facts by a fair preponderance of the evidence. Such items as claimed costs or other financial data are facts which the utility must prove by a fair preponderance of the evidence.

The Commission acts in a legislative mode when it weighs the facts presented and determines if proposed rates are just and reasonable. Acting legislatively, the Commission draws inferences and conclusions from proven facts to determine if the conclusion sought by the utility is justified. The Commission weighs the facts in light of its statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates. In its legislative capacity, the Commission forms determinations such as the usefulness of a claimed item, the prudence of company decisions, and the overall reasonableness of proposed rates.

The utility therefore faces a two part burden of proof in a rate case. When presenting its case in the rate change proceeding, the utility has the burden to prove its facts by a fair preponderance of the evidence. The utility also has the burden to prove, by means of a process in which the Commission uses its judgment to draw inferences and conclusions from proven facts, that the proposed rates are just and reasonable.

X. CONSERVATION IMPROVEMENT PLAN

Minn. Stat. § 216B.16, subd. 1 (1990) requires utilities filing for a general rate increase to include an energy conservation improvement plan (CIP) as that plan is described in Minn. Stat. § 216B.241 (1990). Midwest Gas submitted its plan on October 1, 1990.

The Department expressed concern that the long-term conservation goals presented in the plan did not improve upon the range of projects in the Company's current CIP. The Department recommended acceptance of the Company's plan for purposes of this rate case but indicated that the plan submitted in the next rate case should incorporate the concept of the conservation continuum, i.e. the range of conservation options from audits to more sophisticated projects with potential for greater energy savings such as direct retrofits, rebate programs, and direct assistance for new construction. The Department recommended that the Commission order the Company to incorporate the conservation continuum into its next plan and to discuss in that plan how and when the Company will progress along this continuum.

The Commission agrees with the Department that utility conservation efforts should become more inclusive and effective over time and that the Company's plan should set forth that growth process. However, the Department's suggestion that the Company not improve its plan in this manner until its next rate case is unsatisfactory. The Company may not file another rate case for several years. In these intervening years there would be no plan reflecting the conservation continuum to provide necessary information and guidance. Therefore, the Commission will order the Company, as a compliance item in this rate case, to improve its conservation plan at this time by submitting an amended goal statement. In its amended goal statement the Company must indicate how and when it will progress along the conservation continuum.

XI. TEST YEAR

Midwest proposed a projected test year running from January 1, 1990 through December 31, 1990. No party opposed the Company's proposed test year; the ALJ found the proposed test year appropriate. The Commission agrees with the ALJ and will accept the test year proposed by Midwest.

XII. RATE BASE

In its initial filing, Midwest Gas proposed a rate base of $43,312,860 for the test year. In its December 26, 1990 supplemental filing, the Company revised the amount of its proposed rate base to $43,662,376. The increase primarily resulted from increases in customer growth projections, revised depreciation rates, and the elimination of a capital project.

The Department, the RUD-OAG and the ALJ used the supplemental rate base as a starting point. The Commission will also use this amount as the starting point in its determination and computation of the rate base in this proceeding. Individual rate base issues will be discussed below.

A. Cash Working Capital

Midwest Gas included negative cash working capital of $1,206,039 in its supplemental filing. The Department recommended adjustments to this amount to reflect a shorter billing-to-payment period for Minnesota ratepayers, the elimination of a .5 day lag in the meter reading-to-billing period when a customer is billed the same day as the meter is read, and changes to expense lead days in three categories. The Company agreed with the reasonableness of the Department's proposed lead and lag period adjustments. The Department also recommended adjustments to cash working capital to reflect the effects of its proposed income statement adjustments.[1] Consistent with its approval of these adjustments to the Company's Operating Income Statement, the Commission must adjust the cash working capital figure accordingly. The impact of these adjustments (the Department's lead and lag period adjustments and its proposed income statement adjustments) increase the negative cash working capital to $2,073,837.

In addition, the Commission finds that further adjustments to the working capital figure are required by two additional income statement adjustments it has adopted elsewhere in this Order[2], by the Commission's treatment of acquisition expenses[3], by its final rate base determination and by interest synchronization.[4]

The Commission finds that the net cash working capital impact resulting from these additional adjustments to the income statement and rate base, and from interest synchronization, is a positive $21,634. Based on the above findings and calculations, the Commission concludes that the appropriate test year cash working capital is a negative $2,052,203.

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[1] These income statement adjustments were due to an increase in the billing units used to calculate revenue, allowance of certain conservation expenses, disallowance of certain marketing expenses, and disallowance of certain expenses in Accounts 912 and 916. See this Order, pages 15 to 19.

[2] The Commission has excluded from the Company's income statement its claimed lobbying expenses and Chamber of Commerce dues. See this Order, pages 19 to 20.

[3] See this Order, pages 7 to 13.

[4] Consistent with prior Commission decisions, the Commission will include the cash working capital effects of the final rate determination and interest synchronization. In calculating the effects of interest synchronization, the Commission first removed the effects already included by Midwest in the supplemental rate base, then calculated the effects on an overall basis.

B. Acquisition Adjustment

Midwest Energy Company purchased Donovan Companies, Inc., the parent company of North Central Public Service in 1986. The purchase price exceeded the book value of the assets by approximately $12 million, of which approximately $7 million was allocated to the Minnesota jurisdiction. Midwest is amortizing the $7 million over 30 years at an annual expense of $233,808 and has included this amount in its test year operating expenses. The Company has included the unamortized portion of the purchase price, $5,961,571, as an acquisition adjustment in its rate base.

In determining if an acquisition adjustment may be included in rate base and operating expenses, the Commission must look to the prudence of the investment. Minn. Stat. § 216B.16, subd. 6 (1990) states that the Commission shall give due consideration to evidence of:

> [t]he cost of property when first devoted to public use, to **prudent acquisition cost to the public utility** less accumulated depreciation on each... (emphasis added)

The prudence of an acquisition is best measured by quantifiable benefits to ratepayers. In this case, Midwest has the burden of showing that ratepayers have received quantifiable savings from the Company's purchase of North Central Public Service. Midwest shareholders will be allowed to recover only that amount which the Company can prove equals savings ratepayers have experienced in the 1990 Test Year due to the acquisition.

The Company requested recovery of the entire test-year costs of the acquisition adjustment from ratepayers, arguing that Midwest's Minnesota ratepayers have benefitted, and will continue to benefit, from the 1986 consolidation through actual, tangible net customer benefits. Midwest identified four areas of savings, as follows:

Cost of Capital Savings	$1,515,000
Materials & Supplies Savings	27,560
G & A Expense Savings	232,560
Gas Costs Savings	969,000
Total	$2,744,120

In its initial brief, Midwest estimated that the test year revenue impact of the acquisition totaled $1,249,768, as shown:

Plant in Service	$7,014,091
Reserve	(1,052,520)
Net Plant	$5,961,571
Rate of Return	10.145%
Return	$ 604,801
Taxes	411,159
Revenue Impact	$1,015,960
Annual Depreciation Expense	233,808
TOTAL REVENUE REQUIREMENT IMPACT	$1,249,768

Because total claimed savings of $2,744,120 exceeded the estimated revenue requirement impact of $1,249,768, Midwest claimed that it had demonstrated the benefits provided to ratepayers and the prudence of its investment in North Central. Midwest requested full recovery of the acquisition adjustment.

The Department stated that a utility should recover the costs of an acquisition from ratepayers only if the acquisition provides net benefits to ratepayers that would not have been realized in the absence of the acquisition. While the Department's estimate of $1.7 million in ratepayer savings was less than Midwest's, it was greater than the estimated revenue requirement impact of the adjustment. The Department therefore recommended that Midwest be allowed to recover the test year acquisition costs.

The RUD-OAG argued that quantifying any savings related to the purchase of North Central was questionable, since North Central ceased to exist following the purchase. The RUD-OAG stated that if the Commission determined that the acquisition did result indirectly in ratepayer savings, Midwest had demonstrated savings of only $899,600 - $1,143,018. The RUD-OAG argued that no portion of the adjustment should be allowed, because demonstrated ratepayer benefits do not exceed the estimated revenue requirement impact.

The ALJ believed that Commission policy, as stated in the Inter-City Gas Corporation rate case[5], requires that an acquisition adjustment be treated like any rate base component. This means the Commission must determine that the acquisition adjustment provides benefits to ratepayers and must determine the reasonable value of those benefits. The utility must affirmatively demonstrate that the acquisition itself has resulted in ratepayer benefits greater than the acquisition costs. The ALJ believed that Midwest had demonstrated savings of approximately $1.4 million. Because those savings would result in net positive benefits to ratepayers, the ALJ recommended that the Company recover the acquisition costs.

The Commission agrees with the Department and the ALJ that a utility may be allowed to recover the cost of an acquisition only to the extent it is able to demonstrate that the acquisition provides comparable benefits to ratepayers and that those benefits would not have been realized absent the acquisition. Therefore, the Commission will consider the acquisition-related benefits claimed by Midwest and will allow a revenue requirement impact to the extent the Commission finds those benefits to be reasonable and quantifiable.

1. Cost of Capital Savings

Midwest claimed the acquisition provided ratepayer savings because Midwest's current cost of capital is lower than the costs North Central Public Service would have experienced, absent the merger.

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[5] The ALJ cited In the Matter of the Petition of Inter-City Gas Corporation for Authority to Change its Schedule of Rates for Gas Service in Minnesota, Docket No. G-007/GR-83-317, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (April 10, 1984).

The Company compared its test year weighted cost of debt to an estimated 1990 North Central cost of debt. The 1990 North Central estimate was based on North Central's actual 1985 capital structure, which included a 65.8% common equity ratio. The Company's long-term debt cost was based on the proportion of North Central's to Iowa Public Service's long-term debt cost in 1985. Midwest used its proposed 12.5% return on equity to estimate 1990 North Central cost of capital. After comparing North Central's projected test year cost of capital with Midwest's 1990 cost of capital, Midwest claimed savings of $1,514,805.

The Department and the RUD-OAG agreed with the Company's basic approach to quantifying cost of capital savings but challenged the use of the 65.8% common equity included in North Central's 1985 capital structure. Both argued that the Commission had not considered nor approved a North Central capital structure with 65.8% equity and likely would not have approved such a ratio had North Central filed a rate case. The Department argued that a savings estimate should be based on rates paid by ratepayers prior to the acquisition, and that the Commission had imputed a capital structure including 56.9% common equity in North Central's last rate case. The RUD-OAG pointed out that in a number of electric rate cases since 1985, the Commission had imputed an equity ratio of 45% or less. The RUD-OAG argued that it was likely the Commission would have adopted a 45% equity ratio if North Central still existed and filed a rate case in 1990.

The ALJ stated that it was most reasonable to use the equity ratio approved by the Commission in North Central's last rate case, since rates paid by ratepayers prior to the acquisition would be based on that ratio. The ALJ recommended that the Department's calculation of cost of capital savings be adopted.

The Commission agrees with the parties and the ALJ that the calculation methodology proposed by Midwest provides a reasonable means of estimating the cost of capital savings resulting from the acquisition of North Central Public Service. It is reasonable to compare the Company's test year weighted cost of debt to an estimated 1990 North Central cost of debt, in order to determine if ratepayers have achieved cost of capital savings through the acquisition. The Commission will next determine the appropriate equity ratio to use for a projected North Central rate case in 1990.

In general rate cases, the Commission must closely scrutinize the level of common equity to ensure that ratepayers are not required to pay an unnecessarily high cost of capital. Because the percentage of common equity is, to some extent, within a utility's control and is typically the highest cost capital, the Commission requires that utilities clearly demonstrate that their equity level is reasonable. The Commission notes that, in North Central's last rate case and other recent cases, it has imputed a lower equity ratio than actually exists, in order to balance more properly investor and ratepayer interests. The Commission finds that the Company has not demonstrated that its proposed equity ratio of 65.8%, based upon North Central's pre-acquisition capital structure, would be found reasonable for an existing North Central Public Service.

The Commission also disagrees with the Department and the ALJ that the equity ratio approved in North Central's last rate case provides a sound base for the calculation of savings, when compared to Midwest's test year capital structure. There has not been a showing that an equity ratio found to be reasonable in the 1983 rate case would necessarily be reasonable in a 1990 case. The Commission finds that an equity ratio of 56.9% would result in an excessive cost of capital. A lower equity ratio is necessary to establish North Central's projected 1990 cost of capital and the related acquisition savings.

The Commission agrees with the RUD-OAG that it has imputed equity ratios of 45% or lower in a number of cases since 1985, when it determined that a higher equity could result in ratepayers paying an unnecessarily high cost of capital. The Commission notes, however, that the majority of these cases involved electric, or primarily electric, utilities considerably larger than North Central. Differences in the gas and electric industries, in company size, in the residential versus commercial/industrial nature of the customer base, as well as in capital structure, would support an equity ratio for North Central greater than the 45% imputed in cases involving large electric utilities. In its discussion, Midwest quoted the January, 1991 C.A. Turner Utility Reports, which showed that electric companies nationwide average an equity ratio of 41% while gas utilities average 49%. The Commission finds that an equity ratio of 49%, equal to the nationwide average of gas utilities, will provide the most appropriate base for the calculation of cost of capital savings. The Commission will impute an equity ratio of 49% for an estimated 1990 North Central rate case, in order to calculate cost of capital savings from the North Central acquisition.

Once the equity ratio is established, the Commission must determine how the portion of capital reduced from pre-acquisition equity ratios (from 65.8% to 49%) will be characterized. One possibility would be to include the difference in capital as additional long-term debt; the other possibility would be to include the difference as short-term debt at a cost equal to the prime interest rate. The Commission, in its determination of capital structure discussed later in this Order, has removed short-term debt from the capital structure calculation. Similarly, in the calculation of cost of capital savings, the Commission will not apply the reduction in equity ratio to short-term debt, but will include it as additional long-term debt. The Commission adopts a projected 1990 capital structure for North Central of 49% equity and 51% long-term debt for the purpose of calculating cost of capital savings.

Based on the capital structure approved above, the Commission finds that the acquisition of North Central has resulted in cost of capital savings of $777,621. The Commission will allow Midwest to include the $233,808 annual amortization of the acquisition cost in test year operating expenses and will allow the Company to include an acquisition adjustment in rate base that results in a test year revenue requirement impact equal to the remaining savings of $543,813.

2. Materials and Supplies

Midwest Gas claimed that savings of $27,560 occurred in the test year because the Company's centralized purchasing resulted in lower unit prices for materials and supplies than would have been available to North Central. Neither the Department nor the RUD-OAG opposed the inclusion of this amount in the test year acquisition savings. The ALJ also concurred with the Company's proposed savings.

The Commission agrees with the parties and the ALJ that Midwest has demonstrated savings in purchasing materials and supplies at less than the costs that would have been incurred by North Central. The Commission will allow Midwest to include an acquisition adjustment in rate base that results in a test year revenue requirement impact equal to the savings of $27,560.

3. General and Administrative Expenses

Midwest Gas estimated acquisition savings in general and administrative (G & A) expenses by averaging G & A expenses for the last two years of North Central's operations (1984-5), inflating that average to 1990 dollars using the GNP implicit price deflator, and comparing that average to the 1989-90 average for Midwest Gas - Minnesota. The inflated North Central average exceeded the 1989-90 Midwest Gas average by $232,560. Midwest proposed acquisition savings in this amount.

Midwest presented several other computational methods to support its proposed G & A acquisition savings. The Company analyzed four of the individual areas of G & A expense: salaries, building expenses, excess general liability expense and health insurance. Midwest attempted to quantify acquisition savings by inflating actual 1984 or 1985 expenditures of North Central in these accounts to 1990 values and comparing those values to actual 1990 expenditures of Midwest Gas. The differences identified in this manner totalled $516,124.

Midwest provided two additional comparisons to support its claim of reduced G & A expenses due to the acquisition. In one, the Company compared 1984 spending of North Central and 1990 spending of Midwest Gas to the average spending of a group of comparable companies in those years. In the other, the Company argued that Midwest's spending is proportionately less than North Central's would have been, due to economies of scale.

The Department and RUD-OAG both argued that the Company's main analysis of G & A expense savings was inappropriate because expenses for the 1985 base year were significantly higher than normal. After eliminating 1985 data, the separate analyses performed by the Department and the RUD-OAG indicate no savings when comparing Midwest 1990 G & A expenditures to the pre-merger expenditures of North Central.

The Commission agrees with the ALJ that the Company has failed to prove that $232,560 in G & A savings resulted from the acquisition. The Company has not adequately supported its methodology for arriving at this figure. Neither has the Company successfully repudiated the alternative comparisons of the Department and RUD-OAG, which indicate potential savings far lower than those claimed by Midwest. All the comparisons proposed by the Company require unsupported assumptions to be made in projecting 1990 North Central G & A expenses. The Commission finds that these comparisons are insufficient to establish a reasonable and quantifiable savings amount. The Commission will not allow an acquisition adjustment for the Company's proposed G & A expense savings.

4. Gas Cost Savings

Midwest Gas claimed that Minnesota gas customers realize annual gas cost savings of $969,429 due to the acquisition of North Central. The Company identified two general areas of savings: $304,429 in annual savings from Midwest's ability to conduct timely zone transfers of gas, and $665,000 in annual benefits related to an interconnection with the Natural Gas Pipeline Company.

Midwest claimed that its geographical diversity allowed it to respond to peak demand needs in one operating zone by transferring spot gas from other Midwest operating zones. The Company claimed that the costs of these transfers were less than the costs of the transfer options that would have been available to North Central (purchasing storage, operating peak shaving facilities, or taking penalty gas). The Company identified specific zone transfers resulting in savings of $304,000 in 1989 and $90,820 in 1990. Midwest argued that the $304,000 was more representative of ratepayers' annual savings because 1989 was a "weather normal" year, while 1990 weather in the Minnesota service territory was 21% warmer than normal.

In addition, Midwest contended that its connection of Des Moines, Iowa to a Natural Gas Pipeline Company (NGPC) line created competition between NGPC and Northern Natural Gas (NNG). Midwest claimed that this competition and the related negotiations between Midwest and NNG resulted in direct, recurring benefits of $665,000 to Midwest's Minnesota customers.

Midwest argued that the benefits negotiated have not been extended to other gas utilities in Minnesota and are the direct result of Midwest's actions to establish competition in the Des Moines market. The Company contended that these benefits would not have been available to a current North Central utility, without a significant offsetting investment in facilities or fuel costs.

The Department claimed that savings on specific peak demand transfers should be considered too speculative to support the acquisition adjustment. The RUD-OAG accepted the Company's 1990 test year savings calculation of $90,800 for zone transfers used to offset peak demand. The RUD-OAG argued that the Company's proposed inclusion of non-test year (1989) savings was not warranted even if

1989 was a more "weather normal" year than 1990. The ALJ agreed with the position of the RUD-OAG.

The Department supported $584,000 of the Company's claimed savings of $665,000 related to the interconnection with the Natural Gas Pipeline Company. The RUD-OAG agreed that some savings to Minnesota ratepayers will result from the Iowa pipeline and accepted $223,000 of Midwest's claimed $665,000 interconnection savings. The ALJ concurred with the RUD-OAG.

In order to recover acquisition costs, a utility must show that it has generated benefits for ratepayers, that those benefits are quantifiable, and that those benefits would not have been realized by the ratepayers without the acquisition. The Commission finds that Midwest has not met its burden of demonstrating that its zone transfers will provide a continuing pattern of ratepayer savings or why these transactions should be isolated from other purchasing activity. Neither has Midwest proven that the savings and concessions received from its supplier were not part of a normal business pattern unrelated to the competitive threat created by the Iowa pipeline, or that an ongoing North Central would not have obtained similar benefits in the absence of an acquisition. The Commission finds that the gas cost savings claimed by Midwest are simply too speculative to ensure ongoing ratepayer benefits. The Commission will not allow an acquisition adjustment for these amounts.

C. Rate Base Summary

Based on the above findings, the Commission concludes that the appropriate rate base for the test year is $40,207,736, as shown below:

Utility Plant in Service		$59,348,586
Acquisition Adjustment		4,405,615
Total Investment		$63,754,201
Accumulated Depreciation		$18,291,922
Acquisition Adjustment Amortization		1,052,520
Total Reserve		$19,344,442
Net Utility Plant in Service		$44,409,759
Less:	Deferred Income Taxes	(3,538,839)
	Customer Advances for Construction	(107,432)
	Customer Deposits	(23,417)
	Uncollectible Accounts	(256,178)
	Injuries and Damages	(51,450)
	Misc. Operation Provisions	(26,907)
Add:	Fuel Stocks	1,061,112
	Materials and Supplies	719,707
	Prepayments	73,584
	Working Capital - Time Lag	(2,052,203)
TOTAL RATE BASE		$40,207,736

XIII. OPERATING INCOME STATEMENT

In its initial filing, Midwest Gas proposed test year net operating income of $3,052,262. In its December 26, 1990 supplemental filing, Midwest increased this to $3,060,903. The increase was largely due to revenue increases from revised year- end customer counts.

Except as indicated in the discussion of issues below, the changes proposed by the Company in its supplemental filing are reflected in the operating income statement used by the Commission to decide this rate case. The individual income statement issues will be discussed below.

A. Uncontested Adjustments

1. Test Year Billing Units

To calculate revenues and expenses for its proposed income statement, the Company projected customer numbers and gas sales volumes (hereafter referred to as billing units) for the test year. The Company based its projections on historical data, including billing units for the first six months of the test year, and used a normalization procedure to adjust for abnormal weather.

The Department objected to some of the data and procedures used by the Company to produce test year billing units. Specifically, the Department argued that the weather-normalization procedure used by the Company is prone to underadjustment of sales, that the Company's forecast of sales relies on conflicting and erroneous data collected over too short an historical period, and that the Company's resulting forecast contains errors and lacks a conservation[6] correction.

To correct perceived deficiencies in the Company's method, the Department prepared its own sales forecast. For most of the customer classes receiving firm service, the Department used regression equations relating gas usage per customer per month to indicator variables. The Department stated that the statistical measures for the various regression equations revealed that its equations were more likely to produce accurate forecasts than the equations used by the Company. Because of the relatively small number of customers, the Department used the Company's forecasts of gas usage per customer for firm industrial customers on the Viking Gas pipeline system and for interruptible customers. In addition, while the Department accepted the year-end customer numbers provided by Midwest Gas as appropriate for use in this rate case, the Department produced monthly usage for each customer group by multiplying the estimated number of customers in the group by the matching estimate of monthly use per customer. Total test year usage for each customer group was then obtained by summing the results for the individual months. The result of these adjustments

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[6] Conservation in this context is a catchall term for positive and negative changes in consumption due to usage growth and actual conservation.

was to increase the billing units for the test year and consequently increase the revenue and gas cost figures above those originally proposed by the Company by $631,715 and $365,509 respectively.

The Company indicated its willingness to accept the results of the Department's forecast for rate case purposes. Midwest Gas noted that, excepting weather normalization, the results of the Department's forecast are nearly identical to the Company's forecast. At the hearings, the Department and Midwest Gas indicated their agreement on the specific billing units to be used for calculating revenues under current rates and gas costs.

The Administrative Law Judge found that the Department's forecast of test year sales was reasonable and should be used in developing the income statement for ratemaking purposes.

The Commission finds that the Department's method of calculating billing units is sound and likely to produce more accurate billing unit figures than the Company's original method. The Commission will therefore adopt the billing unit figures obtained using the Department's method. Application of current rate schedules and gas costs to the selected billing unit figures produces upward adjustments of $631,715 and $365,509 from the respective revenue and gas cost figures originally filed by Midwest Gas.

2. Ongoing Conservation Expenses

Midwest Gas indicated that its test year expenses originally included $64,209 in conservation related accounts. The Company proposed in its supplemental direct testimony that amount should be changed to $150,560 to cover costs of its approved Conservation Improvement Program (CIP) and of a conservation library.

The Department indicated that its commissioner had approved a one-year CIP budget for Midwest Gas of $148,560 on December 6, 1990. According to the Department, including this amount in test year expenses is appropriate. However, the Department indicated that the additional $2,000 for the conservation library should not be allowed without further justification from the Company. At the hearings, the Company indicated that it would accept $148,560 as the proper level of expenses to include in the income statement for conservation activities.

The Administrative Law Judge indicated that expenses of $148,560 should be reflected in rates to account for the Company's approved conservation improvement program. He also indicated that Midwest Gas had failed to provide an affirmative justification for the additional $2,000 for the conservation library.

The Commission agrees with the position of the Department and the Administrative Law Judge and will include $148,560 in test year expenses for conservation activities. This amount constitutes an increase of $84,351 from the figure originally filed by Midwest Gas. Recovery of conservation expenses will be subject to the tracking procedures outlined in the Commission's earlier Order on the Company's conservation cost recovery plan. <u>In the Matter of</u>

the Proposed Cost Recovery Plan for Midwest Gas Utility's Conservation Improvement Program, Docket No. G-010/M-90-399, ORDER ESTABLISHING CIP COST RECOVERY PLAN (November 28, 1990).

3. Marketing Expenses

Midwest Gas included in its proposed income statement the projected costs for three marketing programs: the conversion rebate program; the dealer appliance rebate program; and the electric water heater conversion program.

The Department argued that ratepayers should pay for the marketing programs only if they lower rates (i.e., generate sufficient revenues to justify their costs). Based upon its cost-benefit analysis, the Department initially recommended exclusion of $47,500 in expenses for the conversion rebate program ($45,000) and the dealer appliance rebate program ($2,500). The Department indicated that the Company had justified $10,783 in expenses for the electric water heater conversion program. Finally, the Department recommended that the Commission require Midwest Gas to file testimony and supporting analysis on its marketing programs in the next rate case.

After reviewing additional information provided in the Company's rebuttal testimony, the Department reran its cost-benefit analysis for the dealer appliance rebate program. Based upon the results of that analysis, the Department concluded that the expenses associated with the dealer appliance rebate program should also be allowed. However, the Department continued to recommend the disallowance of $45,000 in costs for the conversion rebate program. The Department also indicated that the Company had provided no justification for $3,347 in additional expenses for the electric water heater conversion program beyond the $10,783 earlier recommended for inclusion in the income statement.

At the evidentiary hearings, counsel for Midwest Gas indicated the Company would accept the surrebuttal position of the Department, i.e. disallowance of $48,347.

The ALJ recommended that the Commission accept the position of the Department on the expenses to be included in the income statement for ratemaking purposes. However, the Administrative Law Judge indicated his reluctance to support a requirement that the Company be ordered to file direct testimony and supporting analysis regarding marketing expenses in its next rate case. He stated that the Company has the burden of justifying expenses and should know that it risks disallowance when justification is not provided. Under this analysis, the action recommended by the Department is unnecessary.

The Commission agrees with the analysis by the ALJ. Accordingly, the Commission will remove $48,347 in marketing expenses from the income statement. However, the Commission will not order the Company to submit testimony and supporting analysis on its marketing programs in the next rate case.

4. Other Expenses Included in Accounts 911, 912, and 916

The marketing expenses described above were included in Midwest Gas Account 912. According to the Department, the Company had not accounted for the following other expenses in Accounts 911, 912, and 916: an additional $62,428 in Account 912; $23,858 in Account 911; and $4,080 in Account 916. The Department argued that the Commission should disallow these expenses from the test year income statement unless the Company could provide additional justification for their inclusion. In its surrebuttal testimony, the Department indicated that the rebuttal testimony of the Company had provided adequate justification for the following costs: labor expenses included in Account 911 and 912 and expenditures for business forms in Account 912. However, the Department continued to argue that the following costs should be disallowed from Account 912: $1,566 for the Minnesota Blue Flame commercial gas cooking incentive, $5,000 for an economic development grant to the Coon Rapids Development Corporation, $26,190 for Rock Valley allocated expenses, and $5,000 for a deferred grant for Anoka County. The Department also indicated that the Company still had not justified the $4,080 in Account 916 and that amount should be excluded from test year expenses.

At the start of the evidentiary hearings, counsel for the Company indicated it would accept the surrebuttal position of the Department.

The Administrative Law Judge found the position of the Department to be appropriate, arguing that the expenses recommended by the Department for exclusion had not been adequately justified by the Company.

The Commission agrees with the analysis of the Department and the ALJ and will disallow $41,836 in expenses from Accounts 912 and 916. This amount is in addition to the disallowance of $48,347 discussed above for marketing programs.

5. Lobbying Expenses

Midwest Gas reported that it had included $14,000 for lobbying expenditures in the test year. The RUD-OAG argued that these lobbying expenses should not be charged to Midwest's Minnesota ratepayers and listed a number of rate case orders where the Commission had disallowed lobbying expense.

The Company agreed to withdraw its request to recover these expenses in the current proceeding. The ALJ acknowledged Midwest's agreement to forego recovery of these expenses, and recommended that test year operating expenses be reduced by $14,000.

The Commission agrees with the RUD-OAG and the ALJ that these expenses should be removed from test year expense and will reduce test year general and administrative expense by $14,000 and increase test year income tax expense by $5,666, resulting in an $8,334 increase in test year operating income.

6. Chamber of Commerce Dues

The RUD-OAG argued that Chamber of Commerce dues of $1,530 should be removed from test year operations expense and listed a number of rate cases, including North Central Public Service's last case (Docket No. G-010/GR-83-333), where the Commission had removed these expenses.

The Company agreed to withdraw its request to recover these expenses in the current proceeding. The ALJ acknowledged Midwest's agreement to forego recovery of these expenses, and recommended that test year operating expenses be reduced by $1,530.

The Commission agrees with the RUD-OAG and the ALJ that these expenses should be removed from test year expense and will reduce test year general and administrative expense by $1,530 and increase test year income tax expense by $619, resulting in a $911 increase in test year operating income.

B. Revenues Under Flexible Rate Schedules

The Company asserted that using a standard rate schedule[7] to estimate the annual revenues the Company is likely to receive from customers on flexible rates will overestimate those revenues. In calculating revenues in its proposed income statement, therefore, the Company projected lower revenues from its flexible rate schedules than would be collected under the corresponding standard rate schedules.

The Department and the RUD-OAG both stated that revenues under the flexible rate schedules should be calculated by assuming customers pay for all volumes at the corresponding standard rates. They argued that the Company had failed to provide evidence to support its contention that using a standard rate schedule will overestimate the revenues from customers on flexible rate schedules. For example, they pointed to the lack of evidence in the record on the historical or projected prices of alternative fuels. In support of calculations based on the standard rate, the Department and the RUD-OAG cited an earlier Order by the Commission which allowed rate ceilings for the flexible tariffs to be set as high above the standard rates as the rate floors are set below the standard rates. In the Matter of a Petition from Midwest Gas to Revise Its Flexible Gas Tariffs, Docket No. G-010/M-90-407, ORDER REVISING FLEXIBLE RATE TARIFF (December 3, 1990).

The Department and the RUD-OAG indicated that rate ceilings would not be necessary if there were no concern that flexible rates could exceed the standard rates. Under the Company's viewpoint, they argued, the captive ratepayers would shoulder all of the risk by preventing a potential revenue shortfall for Midwest Gas, but the ratepayers would receive no revenue credits if Midwest Gas collected revenues above what the utility has proposed for

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[7] A standard rate schedule is the tariff schedule a customer would be on if it did not qualify for and choose the flexible tariff.

inclusion in the income statement. In contrast, argued the Department and the RUD-OAG, their position acknowledges the downward and upward flexibility in rates and the corresponding risks to the customers and the Company, as described in the December 3, 1990 Order.

The Administrative Law Judge indicated that the standard rate schedules should be used in calculating projected revenues from customers on flexible rate schedules. He indicated that using the standard rates to project revenues is reasonable because it provides Midwest an incentive to flex a given rate as high as possible and still retain the customers on the system. He also indicated that the Company had failed to meet its burden of proof on this issue.

The Commission agrees with the analysis of the Department, the RUD-OAG, and the Administrative Law Judge. The Commission will adjust flex-rate revenues upward by $55,256 to reflect this determination.

C. Unbilled Revenues

The term "unbilled revenues" refers to revenues a company has earned between the most recent meter reading date and the end of the month. Utility companies bill customers on a cyclical basis throughout the month based on meter readings. The gas usage from each customer's meter reading date to the end of the month remains unbilled until the meter is read and the bill prepared the following month. Unbilled revenues can be a ratemaking issue because, while the utility incurs gas costs in the month service is provided, a portion of the utility's revenues from the sale of that gas to its retail customers is not billed until the month after service. A company's test year may overstate its revenue deficiency if it reflects all gas costs but not the proper level of related revenues.

In its proposed overall test year revenues, Midwest Gas included amounts that it has earned but did not bill for during the test year (1990) and excluded the amounts that it earned but did not bill for in the month immediately prior to the test year (December 1989). This procedure matches test year revenues with the actual gas usage and gas costs incurred during the test year.

The RUD-OAG proposed an adjustment that would include a portion of Midwest's unbilled revenues as of December 31, 1989 in the 1990 test year revenues. The RUD-OAG's proposal would amortize the December 31, 1989 unbilled revenues and offsetting gas costs over four years, resulting in an increase of $712,922 to test year operating revenues and an offsetting increase of $548,278 to cost of gas.

The OAG argued that since the unbilled revenues at the end of 1989 had not previously been reflected in rates paid by customers of Midwest Gas (or its predecessor North Central), customers had been overcharged. To support its proposal, the RUD-OAG pointed out that the Iowa Commission had accepted a ten-year amortization of pre-test year unbilled revenues in a stipulated settlement of Midwest's

1982 rate case; that the Tax Reform Act of 1986 required that unbilled revenues as of the effective date be included in taxable income over a period no longer than four years; and that fairness would require the inclusion of prior period unbilled revenues since Midwest had requested an acquisition adjustment for its 1986 purchase of North Central.

Midwest responded that allowing the inclusion of pre-test year revenues would improperly match more than 12 months of revenue with 12 months of expense and that, by recognizing unbilled revenues at the end of the test year, the Company has properly matched test year expenses and revenues. The Company argued that the decision by the Iowa Commission involved different circumstances, including a stipulated settlement; that the Tax Reform Act required recognition for tax purposes only; and that neither decision should be used as precedent in this case. Finally, the Company pointed out a number of prior Minnesota rate cases, where the Commission had rejected the inclusion of pre-test year unbilled revenues.

The ALJ recommended that the Commission not include the pre-test year unbilled revenues. The ALJ cited the Commission's previous decisions regarding unbilled revenues and noted that the factors listed in those cases also applied in this proceeding. He stated that the RUD-OAG had not offered sufficient reason for a change in Commission policy, nor distinguished the circumstances of this case from those other cases. In considering the RUD-OAG's fairness reasoning, he noted that the allowance of an acquisition adjustment would not be based on fairness, but on whether the Company adequately demonstrated test year benefits sufficient to offset test year acquisition-related costs.

The Commission accepts the ALJ's recommendation. The RUD-OAG's proposal is not new. In a previous rate case, the Commission addressed a proposal from the RUD-OAG to include unbilled revenues in the test year. The Commission found that making an adjustment to recognize the unbilled revenues that exist at the beginning of the test year would result in a gross mismatch of test year revenues and expenses. The mismatch would result from combining approximately 12-1/2 months of revenue with only 12 months of expenses. <u>In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Utility Service for Customers Within the State of Minnesota</u>, Docket No. E-002/GR-85-558, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (June 2, 1986), page 35.

Nor is the RUD-OAG's proposal to amortize the total unbilled revenues as of the beginning of the test year new. In its ORDER AFTER REHEARING AND RECONSIDERATION of its June 2, 1986 Order, the Commission specifically rejected the RUD-OAG's proposal to amortize Northern States Power's (NSP's) unbilled revenues as of the beginning of the test year. <u>NSP</u>, ORDER AFTER REHEARING AND RECONSIDERATION, Docket No. E-002/GR-85-558 (August 6, 1986), pages 2-3. In that case, the Commission found that unbilled pre-test year revenues does not represent a liability owed to the Company's ratepayers as of the beginning of the test year and that amortization of such revenues did not change the nature of such revenues. Similarly in this case, four-year amortization of the unbilled revenues would lessen the mismatch of test year revenues and expenses but not eliminate it.

Regarding the RUD-OAG's tax argument, the Commission finds that while the IRS now requires the inclusion of unbilled revenues in income, with the initial unbilled revenue balance being reported as income over four years, this change in taxation does not require a change in the selection of the appropriate test year for regulatory purposes. The Commission's concern, different from that of the Internal Revenue Service (IRS), is to secure a test year that properly matches 12 months of revenues with 12 months of operating expenses and the appropriate income tax expense. The Company's treatment of unbilled revenues does this.

Based on the above findings, the Commission will not adjust test year revenues to include any portion of out-of-period sales in test year revenues.

D. Operating Income Statement Summary

Based on the above findings, the Commission concludes that the appropriate operating income for the test year is $3,155,317, as shown below:

Operating Revenues:	
Retail Revenue	$45,674,104
Other Revenue	571,104
Total Operating Revenues	$46,245,208
Operating Expenses:	
Gas Purchases	$32,242,593
Production Expense	5,781
Distribution Expense	1,129,734
Maintenance Expense	800,333
Customer Account Expense	1,780,588
Sales Expense	58,466
General and Administrative Expense	2,245,654
Depreciation Expense	2,324,945
Other Taxes	1,708,118
Income Taxes	$ 793,679
Total Operating Expenses	$43,089,891
NET OPERATING INCOME	$ 3,155,317

XIV. RATE OF RETURN

A. Introduction

The overall rate of return authorized by the Commission is the cost of capital which is built into final approved rate levels. It represents the percentage amount which Midwest Gas is allowed to earn on its rate base, or investment in its Minnesota utility operations under test year conditions.

Midwest Gas's rate base is financed by three forms of capital: debt, preferred stock, and common equity. The overall cost of capital is a function of the cost of each of these forms of capital and the relative amount of each form. The overall cost of capital is determined by weighing the cost of each form of capital by its proportion of the entire capital structure and summing the results.

The Commission will first address the capital structure, then the cost of debt and preferred stock, and finally the cost of equity.

B. Capital Structure

The issue to be decided by the Commission is the appropriate percentage amounts of debt, preferred stock and common equity to be included in the capital structure used to determine the overall cost of capital to Midwest Gas.

The Commission finds that the relative proportions of the various forms of capital employed by a utility company must be reviewed to ensure that ratepayers are not being required to pay an unnecessarily high cost of capital resulting from the excessive use of more expensive forms of capital. The use of too much common equity in the capital structure could cause an excessive cost of capital because common equity is typically the highest cost capital.

Because Midwest Gas does not have its own capital structure a reasonable substitute must be selected. Midwest Gas is a division of Iowa Public Service Company (IPS), a regulated utility and a wholly owned subsidiary of Midwest Resources, Inc. Midwest Gas does not seek out its own financing in the capital markets. Financing for Midwest Gas is accomplished through IPS. The Commission finds it reasonable to use the capital structure of IPS as a proxy for the capital structure of Midwest Gas, since the actual financing operations of IPS closely resemble those of Midwest Gas.

Midwest Gas's initial capital structure filing included a component for short-term debt. However, the Department was

opposed to including short-term debt in the Company's capital structure. The Department argued that the capital structure should reflect the Company's long term financing arrangements because the capital structure is used to calculate an overall rate of return which is applied to the Company's rate base. The Department argued that the cost of short-term debt should be treated as an expense.

In its rebuttal testimony Midwest Gas proposed using either of two capital structures, one with short-term debt and the other without. Both capital structures are based on updated numbers for IPS that include actual numbers for the first 11 months of the test year and on estimates for the final month.

In its opening statement at the evidentiary hearing, Midwest Gas proposed using a capital structure that excludes short-term debt, as was proposed by the Department.

RUD-OAG and the Seniors did not address the issue of whether to include short-term debt in the capital structure in their comments.

Midwest Gas and the Department agreed that the following capital structure is appropriate for final, prospective rates:

Long-term debt	46.51%
Preferred stock	9.75%
Common equity	43.74%
Total	100.00%

This is also the capital structure recommended by the ALJ.

The Commission finds that the proposed capital structure is reasonable with respect to the relative proportions of the various forms of capital employed by the Company, and that its use will not result in an unreasonably high overall cost of capital. The Commission concludes that the capital structure as proposed and shown above should be adopted for the purpose of determining the authorized rate of return for final rates.

C. Cost of Debt and Preferred Stock

The issue before the Commission is the appropriate cost rates to apply to the debt and preferred stock component of the capital structure.

Midwest Gas proposed using the following cost rates:

Long-term debt	8.592%
Preferred stock	6.983%

These cost rates reflect the actual cost of IPS's long-term debt and preferred stock. No party disputes that these are the appropriate rates for long-term debt and preferred stock.

The ALJ also recommended that Midwest Gas's proposed cost rates for debt and preferred stock be approved.

The Commission finds that these are the appropriate cost rates to use for determining the Company's overall cost of capital.

D. Cost of Common Equity

The Commission must next determine a fair and reasonable rate of return on common equity for Midwest Gas.

Common equity has a cost determined in the capital market by forces acting on the market as a whole, such as inflation and the general economic outlook, and by concerns peculiar to the specific industry and the specific company. Unlike holders of debt or preferred stock, common shareholders have no contractual right for specified payments. Instead, they have an ownership claim on the residual amounts after interest on bonds and dividends on preferred stock have been paid. Because of this, the cost of common equity cannot be measured directly, but can only be estimated.

Under the DCF method, the cost of equity is inferred by observing past and present market data on the price of the stock and the dividend being paid, and by making reasoned judgments of investor expectations for the future. Investors collectively determine the market price of common stock by their willingness to buy or sell the stock at various prices. Essentially, the DCF analyst is trying to determine what interest rate investors are using to discount the expected future flow of dividends and stock price appreciation to a present value equal to the current price of the stock. That interest rate is the market-required rate of return. The DCF analyst generally makes use of a formula in which the required rate of return is equal to the sum of the dividend yield (the dividend divided by the price) and the growth rate expected by investors.

The Commission finds that the DCF approach is appropriate to use to estimate the cost of equity to Midwest Gas in this proceeding. The Commission finds that the DCF method is firmly grounded in modern financial theory and has been relied on by the Commission in nearly every rate case proceeding since 1978. A fair and reasonable estimate for the cost of capital should be based on past evidence and reasonable judgments concerning future expectations.

1. Summary of Testimony

In this proceeding, the Company's witness Mr. Paul R. Moul, the Department's witness Dr. Eilon Amit, RUD-OAG's witness Dr. Richard M. McIntire, the Seniors' witness Dr. Kenneth M. Zapp, and the ALJ all relied primarily on a discounted cash flow (DCF) analysis to make their estimate of the cost of equity. The Company's witness initially used the DCF model as a supplement to his risk premium analysis. The Department, the Seniors and the Company used the capital asset pricing model (the CAPM) as a check on their results with the DCF.

Midwest Gas, in its opening statement during the evidentiary hearings, stated that the company would accept a 12.50% rate of return on common equity. (This rate is lower than the 13.75% that the company had asked for in its initial filing and in its rebuttal testimony.) 12.50% is the same rate of return on equity proposed by the Department and the RUD-OAG in their surrebuttal testimony. The Minnesota Senior Federation's final proposed rate of return on equity was 12.02%.

a. Midwest Gas

Mr. Moul, testifying for Midwest Gas, performed a risk premium analysis and a DCF analysis to estimate the cost of equity to Midwest Gas. In rebuttal testimony, Mr. Moul also performed an analysis using the capital asset pricing model (the CAPM).

1) DCF Analysis

Mr. Moul relied on an analysis of a comparison group of natural gas distribution companies as the basis for his DCF study. (Mr. Moul also constructed a comparison group of combination gas and electric companies to use as a check on his results using the data from the gas comparison group.) Mr. Moul employed eight selection criteria to choose a sample of companies which were comparable to Midwest

Gas. Mr. Moul applied a DCF analysis methodology to the six companies which met all eight selection criteria.

Mr. Moul determined the dividend yield, the first component of the DCF formula, to be 7.1%. He increased the dividend yield by a factor of 1.0275 to reflect one-half the expected growth in dividends over the next year. This resulted in a dividend yield of 7.3%. Then Mr. Moul made a flotation cost adjustment of 5% by dividing 7.3% by 95%. This resulted in an adjusted dividend yield of 7.68%. To determine the growth rate component of the DCF formula, Mr. Moul looked at the forecasted earnings per share growth rates for his gas comparison group from the Institutional Brokers Estimating Service (IBES) and Value Line. He estimated a growth rate of 5.5%. Combining this growth rate with his dividend yield of 7.68%, he found a DCF-determined cost of equity of 13.18%.

2) Risk Premium Analysis

Mr. Moul also performed a risk premium analysis in which he compared the returns earned on his two comparison groups with the returns earned on long-term public utility bonds. Mr. Moul added the risk premiums for his two comparison groups to the current return on long-term public utility bonds to determine a cost of equity rate for both groups. Mr. Moul used an approximate average of the two calculations and came up with a rate of return on common equity of 14.7%.

3) CAPM Analysis

Mr. Moul also used the CAPM to calculate a rate of return on common equity in response to the Department's calculations using the same model. Midwest Gas used the standard CAPM formula, i.e. $k = Rf + b(Rm-Rf)$; where:

- k was the required rate of return on equity;
- Rf (the risk free rate) was the rate of return on intermediate to long-term treasury obligations;
- Rm (the expected rate of return on the entire market) was the average of the two market rates of return;
- b (beta) was the measure of how an individual stock's market price was affected by changes in the overall rate of return on the market.

Using the CAPM, Mr. Moul calculated a required rate of return on equity of 14.05%.

b. The Department

Dr. Amit, testifying for the Department, performed a DCF analysis and a CAPM analysis to estimate the cost of equity to Midwest Gas.

1) DCF Analysis

Dr. Amit relied on an analysis of a comparison group of natural gas distribution companies for his DCF analysis. (Dr. Amit constructed two additional comparison groups, one a group of combination gas and electric companies and the other a group of electric companies, to use as a check on his results with the gas comparison group.) Dr. Amit employed five selection criteria to choose a sample of companies which were comparable to Midwest Gas. Dr. Amit applied the DCF model to the seven companies which met all five selection criteria.

Dr. Amit determined the dividend yield to be 6.60%. He increased the dividend yield by a factor of 1.02685 to reflect one-half the expected growth in dividends over the next year. This resulted in a dividend yield of 6.78%. Then Dr. Amit made a flotation cost adjustment to the dividend yield figure of 5% by dividing 6.78% by 95%. This resulted in an adjusted dividend yield of 7.13%. To determine the dividend growth rate component of the DCF formula, Dr. Amit looked at the historical growth rate of book value per share, adjusted dividends per share, adjusted earnings per share and the forecasted growth rates, for his gas comparison group, from Icarus, which is prepared by Zacks Investment Research, Inc. and Value Line. He estimated a growth rate of 5.37%. Combining this growth rate with his dividend yield of 7.13%, he found a DCF-determined cost of equity for the gas comparison group of companies of 12.50%.

2) CAPM Analysis

Dr. Amit used the CAPM as a check on his results using the DCF model. The Department used the standard CAPM formula. The Department made four CAPM calculations with results that ranged from 10.06% to 11.82%.

c. RUD-OAG

Dr. McIntire testifying for the RUD-OAG, performed a DCF analysis to estimate the cost of equity to Midwest Gas.

Dr. McIntire relied on data for a comparison group of natural gas distribution companies as the basis for his DCF model. Dr. McIntire employed five selection criteria to choose a sample of companies which were comparable to Midwest Gas. Dr. McIntire applied his DCF model to the nine companies which met all five selection criteria.

Dr. McIntire determined the dividend yield to be 7.2%. He increased the dividend yield by 1.025 and 1.026 to reflect one-half the expected growth in dividends over the next year. This resulted in a range of expected dividend yields of 7.38% to 7.387%. To determine the dividend growth rate component of the DCF formula, Dr. McIntire looked at the projected growth rate of earnings per share, dividends per share and book value per share, for his gas comparison group from Value Line. He estimated a range for his growth rate of 5.0% to 5.2%. Combining these growth rates with his dividend yields of 7.38% and 7.387%, he found a DCF-determined cost of equity for his gas comparison group of companies of 12.50%.

d. Minnesota Senior Federation

Dr. Zapp, testifying for the Seniors, performed a DCF analysis and a CAPM analysis to estimate the cost of equity to Midwest Gas.

1) DCF Analysis

In his DCF analysis, Dr. Zapp relied on the data supplied by Mr. Moul in his direct testimony regarding the Company's comparison group of natural gas distribution companies.

Dr. Zapp determined the dividend yield, the first component of the DCF formula, to be 7.1%. He increased the dividend yield by a factor of 1.02375 to reflect one-half the expected growth in dividends over the next year. This resulted in a dividend yield of 7.269%. To determine the dividend growth rate, Dr. Zapp looked at the earnings per share growth rate forecast from IBES and the dividends per share growth rate forecast from Value Line. He estimated a growth rate of 4.75%. Combining this growth rate with his dividend yield of 7.269%, he found a DCF-determined cost of equity of 12.02%.

2) CAPM Analysis

Dr. Zapp also used the CAPM. Dr. Zapp made two calculations using the standard CAPM formula. (For beta, Dr. Zapp used the value line beta for Midwest Energy Company. Midwest Energy was the parent company of Midwest Gas before Midwest Energy merged with Iowa Resources to become Midwest Resources, Inc.) The results of Dr. Zapp's calculations using the CAPM were for a rate of return on common equity ranging from 10.78% to 11.1%.

2. ALJ's Recommendation

The ALJ recommended a 12.50% rate of return on equity and found that the DCF model was an appropriate method to use for making this determination. The ALJ also noted that the Department and the RUD-OAG arrived at a 12.50% rate of return on equity while using the DCF model, but by using different variables in the formula.

The ALJ indicated a preference for the OAG's version of the DCF model for two reasons. The first reason was that the OAG used a 12 month period for calculating the dividend yield when the Department had relied on a month's worth of dividend data. The ALJ found that the Commission's practice has been to use 12 months of data for this purpose.

The second reason the ALJ found was that the Department included a flotation cost adjustment in its model. The ALJ did not find any evidence in the record that supported compensating the Company for the issuance of new stock.

3. Commission Discussion

a. Discounted Cash Flow (DCF) Model

The Commission first must decide whether it is reasonable and appropriate to apply the DCF analysis to the data of a comparable group of other companies.

The Commission agrees with the witnesses that it is not practical to apply the DCF approach directly to Midwest Gas data. Investors cannot purchase shares in Midwest Gas because it is a division of Iowa Public Service Company. Because investors cannot directly purchase shares of Midwest Gas, no unique yield or growth rate can be determined for Midwest Gas. Therefore, it is appropriate to apply the DCF method to a comparable group of gas distribution companies.

Therefore, the Commission finds it is necessary to analyze the cost of equity for a group of utilities with comparable risk to Midwest Gas's operations in Minnesota. The Commission concludes a DCF-determined cost of equity to a comparable group is a suitable proxy for the cost of equity for Midwest Gas.

Next, the Commission will address the issue of which DCF study applied to a comparable group of companies provides the best estimate of the cost of equity to Midwest Gas.

The DCF estimates of the cost of equity to Midwest Gas, based upon the analysis of a comparable group, fell within a relatively narrow range. Four expert witnesses testified to a specific rate of return on common equity to be applied to Midwest Gas. Three of the witnesses, including the Company's witness, Mr. Paul R. Moul, have concluded that a reasonable estimate of the cost of equity to Midwest Gas for ratemaking purposes is 12.50%. The Department's witness, Dr. Eilon Amit, and RUD-OAG witness, Dr. Richard M. McIntire, while working independently of each other, have estimated that the cost of equity to Midwest Gas is 12.50%. Minnesota Senior Federation's witness, Dr. Kenneth M. Zapp, recommended a rate of return on equity of 12.02%.

The results of these analyses indicate that there is more agreement than disagreement among the witnesses. The Commission finds that all studies were generally credible and provide an indication of the cost of equity to Midwest Gas.

However, the Commission finds that the DCF analysis conducted by Dr. McIntire is the most reasonable. The Commission selected Dr. McIntire's testimony over Dr. Amit's for the following reasons. The first reason relates to the length of the period selected by Dr. Amit for calculating the dividend yield. Dr. Amit indicated that historical dividend yields are not useful indicators of future dividend yields and that the most recent dividend yield incorporates all relevant information. Therefore, according to Dr. Amit, a 4-week analysis of closing prices was adequate for computing the dividend yield. The Commission agrees with the ALJ that using a 12 month period is more reasonable.

The other reason the Commission has not adopted Dr. Amit's testimony is his inclusion of a flotation cost adjustment for issuance of stock. In this case, as noted by the ALJ, Midwest Gas has failed to affirmatively establish facts that support a flotation cost adjustment.

The Commission next turns to the DCF analysis performed by Dr. Zapp. Dr. Zapp recommended a cost of equity of 12.02%, based on Mr. Moul's comparison group of gas utilities. The Commission finds that Dr. Zapp's testimony is inconsistent because he criticized the comparability between Mr. Moul's comparison groups and Midwest Gas but then used these groups and the data from these groups in his own analysis.

The Commission also finds that Dr. Zapp did not adequately support his growth rate estimate. Dr. Zapp stated that the proper method would be to take the average of the Value Line growth projection for dividends per share and the mean IBES growth projection of earnings per share but he did not make any other explanation other than this would be the proper approach.

The Commission also finds Dr. Zapp's use of the DCF model is inconsistent. In direct testimony he adjusted the cost of equity capital upwards from 11.55% to 12.0% because of the uncertainty currently in the financial markets. Dr. Zapp made this adjustment without providing any quantitative basis to support the increase in the cost of equity capital. In surrebuttal testimony, Dr. Zapp again rounded his cost of equity capital upwards from an average of 11.865% to 12.0%. However, no reason was specified other than rounding.

b. RUD-OAG's DCF Model

1) RUD-OAG's Gas Comparison Group

The nine distribution companies selected by Dr. McIntire are reasonable proxies for Midwest Gas and are therefore appropriate for inclusion in the comparable group of companies used for determination of an appropriate dividend yield.

2) RUD-OAG's Dividend Yield

The Commission finds that Dr. McIntire's proposed adjusted dividend yield of 7.38% to 7.387% provides the most reasonable dividend yield for use in estimating the cost of equity to the comparable group.

This range was based on dividend yield data for the RUD-OAG's gas comparison group of companies for a 12 month period ending December 31, 1990. The OAG used current monthly dividend yields for each of the companies in its gas comparison group. These yields were calculated by annualizing the current quarterly dividends per share and dividing by the monthly high-low average share price. The resulting monthly dividend yields were then averaged, by company, to produce an average annual dividend yield for the test year 12 month period. Dr. McIntire then adjusted the dividend yield upward by multiplying it by one-half the expected dividend growth rate.

The Commission finds that Mr. McIntire's dividend yields provide a better balance of current and longer term yields than does Dr. Amit's average of the yields from the last 24 trading days. The Commission finds that Dr. McIntire's averaging of monthly dividend yields reasonably reflects current market conditions, is representative of investor expectations for the regulatory period, and is long enough to smooth the effect of any temporary market fluctuations.

3) RUD-OAG's Dividend Growth Rate

The growth rate should reflect the rate at which investors expect dividends to increase in the future. To estimate investor expectations, it is reasonable to presume that investors consider historical growth rates and forecasted growth rates. All the analysts presenting rate of return testimony in this proceeding considered these factors.

The Commission agrees with the ALJ's recommendation and finds that Dr. McIntire's growth rate range of 5.0% to 5.2% provides a reasonable estimate of investors' growth expectations. This range is reflective of the range of growth figures presented in the record, i.e. it is between the 4.75% suggested by the Seniors and the 5.5% suggested by the Company.

c. Risk Premium Analysis

The Commission next turns to the question of whether the risk premium study presented by Mr. Moul provides a reasonable estimate of the cost of equity to the comparison group.

The Department, the RUD-OAG and the Seniors all recommended that the risk premium method should not be used to estimate the cost of equity to Midwest Gas.

The Commission agrees that it is inappropriate to use a risk premium analysis to determine the cost of common equity. The risk premium method has not been shown to be a reliable indicator of the cost of equity. The Commission has consistently rejected this approach for estimating the cost of equity because of the volatility of results from this method. Nothing in this record demonstrates that its policy should be changed.

d. Capital Asset Pricing Model (CAPM) Analysis

The Department's witness Dr. Amit used a CAPM as a check on the reasonableness of his DCF analysis. Dr. Amit's calculations using the CAPM determined a range from 10.06% to 11.82% for the cost of equity to Midwest Gas. Midwest's witness, Mr. Moul performed a CAPM analysis in his rebuttal testimony and derived a return on equity of 14.05%. The Senior's witness, Dr. Zapp also performed a CAPM analysis and derived a range for the cost of equity to Midwest Gas of 10.78% to 11.1%.

The basic premise of a CAPM analysis is to measure the systematic risk of a stock by using the beta coefficient. The CAPM determines the return by using a risk premium which measures the beta of the company or the group's stock compared to that of a market portfolio. This amount is then added to the return on a riskless asset. The CAPM raises the difficult issue of determining the appropriate beta, the appropriate riskless asset, and the effect of taxes. Thus, the parties used the CAPM only as a support for their DCF analyses. The Commission notes the wide range in the cost of equity figures derived by the parties using the CAPM. The Commission finds that this may be useful as supplemental information but that it does not alter its reliance on the DCF model for determining a rate of return on equity.

e. Conclusions

The Commission finds that the DCF-determined cost of equity of 12.50% discussed above is the best estimate of the cost of equity for Midwest Gas. This result is based on a group of utilities which the Commission has found is risk comparable to Midwest Gas.

E. Overall Rate of Return

Based on the Commission's findings and conclusions on rate of return on equity, cost of debt and preferred stock, and capital structure made herein, the Commission concludes the overall rate of return for Midwest Gas in the test year is 10.144%, calculated as follows:

	% of Total	Cost	Weighted Cost
Long-Term Debt	46.51%	8.592%	3.996%
Preferred Stock	9.75%	6.983%	.681%
Common Equity	43.74%	12.500%	5.467%
	100.00%		10.144%

XV. REVENUE DEFICIENCY

The above Commission findings and conclusions result in a Minnesota jurisdictional gross revenue deficiency of $1,551,076, determined as shown below:

Rate Base	$40,207,736
Rate of Return	10.144%
Required Operating Income	$ 4,078,673
Test Year Operating Income	3,155,317
Operating Income Deficiency	$ 923,356
Revenue Conversion Factor	1.679825
Revenue Deficiency	$ 1,551,076

In the test year income statement, the Commission found that revenue from retail sales of gas at present rates is $45,674,104. In addition, other revenues total $571,104, resulting in total test year revenue from Minnesota customers at present rates of $46,245,208. Adding $46,245,208 to the gross revenue deficiency of $1,551,076 results in total authorized test year revenue from Minnesota customers of $47,796,284.

XVI. RATE DESIGN

In this case the Company proposed several significant changes to existing rate design. It proposed to stop applying different rate schedules to customers served by Viking Gas pipeline and Northern Natural Gas pipeline. It proposed an increase in the customer charge for all classes. It proposed to collect nearly all of the remaining revenue deficiency from Small Firm (chiefly, residential) customers. It proposed to create a new Medium Firm customer class. It proposed to begin offering Large Volume Interruptible Rates (LVI) to certain off-peak and high growth loads which would not otherwise meet LVI eligibility requirements.

The Company also proposed several miscellaneous rate design changes: an increase in its reconnection charge, daily instead of monthly calculation of customer charges, and replacement of the Winter Period Surcharge with a monthly storage gas adjustment.

Finally, the Department reviewed the Company's current tariffs as part of its rate case analysis and recommended the following changes: language changes in the flexible rate tariff to comply with the terms of an earlier Commission Order, elimination of the Special Contracts Provision in the Company's interruptible tariffs, technical changes to tariff refund provisions to comply with the Purchased Gas Adjustment rules, and minor changes to tariff provisions on access to customer premises to comply with the Customer Service Rules.

These issues will be taken up individually.

A. Rate Differential for Source of Supply

The issue before the Commission is whether to allow Midwest Gas to consolidate the rate schedules of customers receiving gas through the Viking Gas pipeline (Viking) and Northern Natural Gas pipeline (Northern). The Company currently has separate rates for these two sets of customers, because they are served by different suppliers and different distribution systems. There are approximately 1,000 customers on the Viking tariff and 70,000 on the Northern tariff. The Company proposed consolidating the two rate schedules for purposes of administrative convenience. Consolidation would raise rates for Viking customers substantially.

The Department opposed consolidation. The RUD-OAG opposed it, too, but recommended phase-in over two general rate cases if the Commission allowed consolidation. The Company said it could accept a phase-in, but preferred immediate consolidation. The ALJ rejected consolidation on equity grounds and recommended the Commission adopt the RUD-OAG phase-in proposal if it decided to permit consolidation.

The Commission rejects the Company's consolidation proposal, for the reasons set forth by the ALJ. The Commission finds that the two supply and distribution systems are physically separate and distinct. There is no interconnection allowing Midwest Gas to transfer gas between the Northern and Viking pipelines on a regular basis. The Company has no definite plans at this point to establish a more reliable interconnection. The Company operates two separate systems for purchasing and transporting gas to the two sets of customers and will continue to operate two separate systems for the foreseeable future.

Furthermore, there are substantial cost differences between the two systems. The cost of gas is lower for customers served by Viking. Fixed system costs are also lower for Viking customers, due to the age of the distribution system and lower growth rates. Cost is an important factor in rate design, and lower costs of providing service are normally reflected to some extent in lower rates. Here the only justification for failing to reflect lower costs in rates for Viking customers would be the cost savings resulting from combining the two rate schedules. The Company has not quantified those cost savings. Clearly, however, they do not offset the effects of combining the costs of both pipelines, since Viking customers would see substantial rate increases upon consolidation. The Commission concludes it would not be just and reasonable to consolidate the two rate schedules and impose substantial rate increases on customers served by the Viking system.

B. Customer Charge

The issue for Commission decision is whether to accept the Company's proposed increases in the Customer Charge.

Midwest recommended the following increases in the customer charge: $1 on a $3 base or a 33 percent increase for the Small Firm (chiefly, residential) class; $22 on a $3 base for the new Medium Firm class; $5 on a $20 base or a 25 percent increase for the Small Volume Interruptible class; and $20 on a $80 base or a 25 percent increase for the Large Volume Interruptible, the Flex Interruptible and the Flex Transport classes.

The Company contended the proposed increases in the customer charge better reflect the specific costs of serving the various customer classes and would therefore allow a more equitable recovery of customer costs. The Company also argued a higher customer charge would reduce the magnitude of future rate increases by improving revenue and earnings stability as fewer fixed costs were loaded into charges applied to weather-sensitive sales. Finally, the Company stated the increase would benefit consumers by leveling out bills in the winter heating season, reducing the financial impact of adverse weather conditions.

The RUD-OAG did not oppose the proposed increases in the customer charge, but argued the increased revenue and earnings stability they would produce should result in a lower rate of return on equity than would otherwise be appropriate.

The Department supported the proposed customer charges as reasonable and equitable. The Department stated the proposed level of the customer charge for each class represented approximately one-half of the customer costs imposed by that class and were consistent with similar charges imposed by other gas utilities.

The Minnesota Seniors recommended that the Small Firm customer charge be set low and that the revenue deficiency be recovered from the energy portion of customers' bills. The Seniors argued that a higher energy charge would make consumption more price-sensitive and provide a greater incentive for customers to conserve. Finally, they argued that the proposed increase in the customer charge, combined with the proposed increase in the energy charge, would result in a total residential rate increase that was unreasonably high.

The Commission agrees with the Company and the Department that the proposed increases in the customer charge are generally reasonable and appropriate. They will provide greater precision in matching cost recovery with cost causation and will increase revenue stability. At the same time, however, the Commission agrees with the Seniors that the increase proposed for the Small Firm (chiefly, residential) class is excessive. The increase would be especially burdensome for low-use residential ratepayers, a group meriting special concern, whether their low usage is due to conservation or financial hardship. The Commission will therefore limit the increase in the customer charge for Small Firm ratepayers to $.50, while approving the proposed increases for other classes.

C. Allocation of the Revenue Requirement

The issue for Commission decision is how to allocate responsibility for the portion of the revenue requirement remaining after assessment of the customer charge. The Company's Class Cost of Service Study indicated substantial subsidization of the Small Firm class by the other four classes. The Company therefore proposed to allocate the remaining revenue deficiency, after the increase in the customer charge, to Small Firm customers.

The Department performed its own Class Cost Of Service Study, maintaining the separation of the Viking and Northern pipeline systems. The methodology used by the Department was similar to the Company's. While the Department essentially agreed with the Company's proposal, the specific margins are different due to the different positions on the consolidation of pipelines. The Department pointed out that the Company's single largest cost is for gas purchases, which account for 67 percent of its total costs. The Department's analysis directly assigns actual gas costs to the respective classes while the Company's approach assigns average, consolidated gas costs. The Department maintained that its study results in reasonable estimates of class cost responsibilities and should be used for setting rates. The RUD-OAG and the Minnesota Seniors recommended a 1% across-the-board increase in bills for all customer classes, to avoid rate shock, further policy goals, and allow for imprecision in the economic analysis of the Company and the Department. The ALJ recommended adoption of the position of the Seniors and the RUD-OAG.

The Commission agrees with the ALJ that allocating the remainder of the revenue requirement to the Small Firm class would be inappropriate, even though that class is currently bearing a smaller portion of its cost of service than other classes. Although the Commission generally supports the movement toward cost-based pricing, there are non-cost factors that are equally important. Avoiding rate shock is a primary ratemaking goal, because sudden, drastic increases in energy costs can be burdensome for residential and non-residential ratepayers alike. Avoiding rate shock is particularly important for residential ratepayers, however, because increases in the cost of basic needs can cause hardship for customers on low or fixed incomes.

Furthermore, cost studies and their underlying economic theories necessarily involve some imprecision. For example, the RUD-OAG correctly notes that the Company's economic efficiency argument probably assumes greater demand elasticity on the part of non-residential ratepayers than actually exists. This imprecision adds to the Commission's unwillingness to place the brunt of the rate increase on residential customers.

The Commission concludes that the most reasonable course of action would be to move the Company's rate structure toward a firmer cost basis, while protecting residential ratepayers from rate shock and preserving flexibility in future ratemaking. Applying a minimum rate increase of one percent to each customer class will accomplish these objectives.

However, the Commission will not include the flexible rate classes in this minimum increase. By their nature, the flexible rate schedules have no fixed commodity rate upon which to apply an increase. As a result, there is no assurance that the Company could collect the increases assigned to the flexible rate classes. Excluding the flexible rate classes from the increase will not be unfair, since they will receive an increase as a result of the approved increase in the customer charge.

A remaining issue is how to collect any deficiency remaining after assessment of the general 1% rate increase. Any remaining deficiency should be small enough to be collected from the Small Firm class without jeopardizing the rate shock principles discussed above. The Commission will therefore direct Midwest Gas to collect the remaining revenue deficiency, after the revenues generated from the increased customer charge and the application of the minimum of one percent increase in the final bill for all classes discussed above, to be collected from Small Firm customers through an increase in the commodity rate.

D. Medium Firm Class

The issue before the Commission is whether to allow Midwest to create a Medium Firm class.

Midwest Gas proposed to establish a new Medium Firm class for customers using between 500 and 1,999 therms per day. The Department and the RUD-OAG supported the new class, although both parties urged the Commission to require the Company to conduct a load survey of members of the new class and report back to the Commission in the next general rate case. The RUD-OAG also suggested that a 400 therm eligibility threshold might be as appropriate as the 500 therm threshold proposed by the Company.

The ALJ recommended acceptance of the new class; he also recommended examination of class load characteristics and most appropriate eligibility threshold in the next rate case.

The Commission agrees with the parties and the ALJ that it is appropriate for the Company to establish a new Medium Firm class. Establishing Medium Firm rates would recognize the economies of scale that result from serving loads in that size range, furthering the general policy goal of aligning cost and price. The Commission also agrees it would be prudent to require the Company to conduct a study to verify the actual load factors of customers in the new class and to examine in detail, in light of the load study and experience with the new class, whether 500 therms is the most appropriate eligibility threshold. The Commission will require the Company to conduct such a study and to report on the results in the next general rate case.

E. Special Provision

The issue for Commission decision is whether to allow Midwest Gas to establish a Special Provision to provide service under the Large Volume Interruptible tariff for loads which often do not meet the minimum requirements for service under the tariff.

This Special Provision would allow the Company to provide service under the tariff to air conditioning, cogeneration, natural gas vehicles, and similar loads whether or not the loads meet the usage threshold necessary to receive service under the tariff. Midwest Gas intends to use the provision to provide an incentive to attract loads that are either off-peak or have potentially high load factors. These loads often use less than 2,000 therms per day, which is the threshold for the Large Volume Interruptible tariff.

The Department opposed the Special Provision, stating that rates are set to recover costs allocated on the basis of customers' load characteristics. The Department stated that the customer's end-use should not determine eligibility for service under various tariffs; rather, customers should receive service based on their load characteristics. The Department also indicated that the Special Provision is inconsistent with the application of the Company's present tariffs. The ALJ agreed with the Department.

The Commission, too, believes it would be inconsistent with established ratemaking principles to approve the Special Provision proposed by the Company. Rate design classifications are based on load characteristics, mainly the amount and time of usage, because these factors directly affect the cost of serving the load. Using objective and cost-related criteria to classify loads for rate setting purposes protects against the preferential or discriminatory treatment prohibited by statute. Minn. Stat. § 216B.03 (1990). Only a compelling public policy rationale could justify granting targeted customers lower rates than their load characteristics dictated, and none has been shown here. The Commission will therefore reject the Company's proposal to establish a Special Provision to attract new loads.

F. Winter Period Surcharge

The issue before the Commission is whether to allow the Company to eliminate its Winter Period Surcharge and instead apply a monthly storage gas adjustment.

Midwest Gas proposed to remove the surcharge provision and replace it with a monthly storage gas adjustment. The Company argued that only the Small Volume Interruptible class applies the Winter surcharge and the monthly adjustment would be easier to administer. The Department recommended acceptance of the Company's proposal but suggested the adjustment only be applied to customers on the system supplied by the Northern Natural Gas. Only customers on the Northern system can use storage gas. The Department argued that applying a storage adjustment is consistent with the collection of these costs from the Small Firm class and with the recovery of costs for other types of storage services.

The Commission finds it is appropriate to recover storage costs through a monthly adjustment in order to promote administrative efficiency and to maintain consistency with the recovery of costs for other types of storage services. The Commission agrees with the Department's recommendation to allow the adjustment and apply it to customers with service from the Northern system only. Given the Commission's decision on the continued separation of rates on the Viking and Northern pipeline systems, it is appropriate that the storage gas adjustment be applied only to the customers on the Northern system, as only they are able to receive storage gas.

G. Reconnection Charges

The issue for Commission decision is the appropriate level of reconnection charges.

Midwest Gas proposed increasing the reconnection charges from $10 to $20 during normal business hours and from $15 to $30 for all other reconnections. The Department reviewed the Company's calculations and performed its own analysis. During the Department's investigation the Company indicated that only certain work is performed during an after-hours reconnection. The Department concluded there is essentially no difference in the cost of reconnection whenever it is performed. The Department estimated the cost of reconnection at $21.16 during normal business hours and $22.86 for all other hours and recommended a flat charge of $20 for all reconnections. The Company, for the purposes of this proceeding, accepted the Department's calculations but proposed a charge of $21 for reconnections during normal business hours and $23 for other reconnections. The Department and the ALJ concurred with the Company's final proposed charges.

The Commission finds the reconnection charges of $21 during business hours and $23 for all other times to be reasonable and closely in line with the actual cost of reconnection. The new reconnection charges will be approved.

H. Special Contracts Provision

The issue before the Commission is whether to allow Midwest to maintain its Special Contracts Provision, under which it offers flexible rates to small volume and large volume interruptible customers it believes might otherwise bypass its system.

The Company views the Special Contracts Provision as a competitive tool to allow it to retain customers that might be lost to alternative fuels or bypass. Midwest Gas points out that the Special Contracts Provision has been a part of its small and large volume interruptible tariffs since 1974. The Department opposed continuation of the Special Contracts Provision as arbitrary and inconsistent with the flexible gas rates statute, Minn. Stat. § 216B.163 (1990). The ALJ adopted the position of the Department.

The Commission agrees with the ALJ that, since the enactment of Minn. Stat. § 216B.163 (1990), flexible gas rates can only be offered in accordance with its terms. The Commission finds the Special Contracts Provision to be inconsistent with the statute. The Company has not proven, to the Commission's satisfaction, that effective competition exists which would allow Midwest to offer flexible rates to these customers under Minn. Stat. § 216B.163, subd. 2 (1990). The Commission will require the Company to remove the Special Contracts Provision from its tariffs.

I. Miscellaneous Tariff Provisions

Several issues which were addressed by the parties early in the proceeding were no longer issues at the end of evidentiary hearings. The Company withdrew its proposal to begin calculating customer charges on a daily instead of monthly basis, stating it may file a similar proposal in a miscellaneous proceeding after further study.

The Company also agreed to make certain amendments to existing tariffs to bring them into full compliance with Commission rules or Orders. As part of its rate case analysis the Department thoroughly examined all Company tariffs, existing and proposed. This review disclosed instances in which tariffs were inadvertently out of compliance with rules or Orders.

The Company has agreed to amend its tariff provisions on customer refunds to comply with the Purchased Gas Adjustment Rules and to amend its tariffs on access to customer premises to comply with the Customer Service Rules. Finally, the Company has agreed to amend portions of its Flexible Rates Tariff to conform with the requirements of the Commission Order authorizing those rates.

ORDER

1. Midwest Gas is entitled to increased annual revenues of $1,551,076 to produce total annual operating revenues of $47,796,284 from Minnesota retail customers.

2. Within 30 days of the date of this Order, Midwest Gas shall file with the Commission for its review and approval, and serve on all other parties in this proceeding, revised schedules of rates and charges reflecting the revenue requirement and the rate design decisions contained herein. The Company shall include proposed customer notices explaining the final rates. Parties shall have 15 days to comment on the compliance filing.

3. Within 30 days of the date of this Order, if Midwest Gas feels it necessary to recover the difference between interim rates and the final increase granted herein in the period from the date of this Order until implementation of final rates, it shall file a proposal for doing so with the Commission, for its review and approval.

4. Within 90 days of this Order, Midwest Gas shall submit a revised goals statement for its Conservation Improvement Plan. Midwest Gas shall incorporate the concept of the conservation continuum into its goal statement and shall indicate how and when the Company's conservation programs will progress along this continuum.

5. Midwest Gas shall conduct a load study to verify the actual load factors of the new Medium Firm Class and to further evaluate the appropriateness of the 500 therm threshold for the class. The results of this study shall be presented and discussed by the Company in its next general rate case filing.

6. Midwest Gas shall track conservation expenses in accordance with this Order and the Commission's November 28, 1990 Order Establishing CIP Cost Recovery Plan in Docket No. G-010/M-90-399.

7. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Richard R. Lancaster
Executive Secretary

(S E A L)

Commissioners Peterson and Kitlinski dissenting.

We respectfully dissent.

In determining if an acquisition adjustment may be included in rate base and operating expenses, the Commission must look to the prudence of the investment. Minn. Stat. § 216B.16, subd. 6 (1990) states that the Commission shall give due consideration to evidence of:

> [t]he cost of property when first devoted to public use, to **prudent acquisition cost to the public utility** less accumulated depreciation on each... (emphasis added)

The prudence of an acquisition is best measured by quantifiable benefits to ratepayers. In this case, Midwest has the burden of showing that ratepayers have received quantifiable savings from the Company's purchase of North Central Public Service.

Midwest identified four areas of savings, as follows:

Cost of Capital Savings	$1,515,000
Materials & Supplies Savings	27,560
G & A Expense Savings	232,560
Gas Costs Savings	969,000
Total	$2,744,120

In its initial brief, Midwest estimated that the test year revenue impact of the acquisition totaled $1,249,768, as shown:

Plant in Service	$7,014,091
Reserve	(1,052,520)
Net Plant	$5,961,571
Rate of Return	10.145%
Return	$ 604,801
Taxes	411,159
Revenue Impact	$1,015,960
Annual Depreciation Expense	233,808
TOTAL REVENUE REQUIREMENT IMPACT	$1,249,768

Because total claimed savings of $2,744,120 exceeded the estimated revenue requirement impact of $1,249,768, Midwest claimed that it had demonstrated the benefits provided to ratepayers and the prudence of its investment in North Central. Midwest requested full recovery of the acquisition adjustment.

The Department stated that a utility should recover the costs of an acquisition from ratepayers only if the acquisition provides net benefits to ratepayers that would not have been realized in the absence of the acquisition. While the Department's estimate of $1.7 million in ratepayer savings was less than Midwest's, it was greater than the estimated revenue requirement impact of the adjustment. The Department therefore recommended that Midwest be allowed to recover the test year acquisition costs.

The RUD-OAG argued that quantifying any savings related to the purchase of North Central was questionable, since North Central ceased to exist following the purchase. The RUD-OAG stated that if the Commission determined that the acquisition did result indirectly in ratepayer savings, Midwest had demonstrated savings of only $899,600 - $1,143,018. <u>The RUD-OAG argued that no portion of the adjustment should be allowed, because demonstrated ratepayer benefits do not exceed the estimated revenue requirement impact.</u> (emphasis added)

The ALJ believed that Commission policy, as stated in the Inter-City Gas Corporation rate case[8], requires that an acquisition adjustment be treated like any rate base component. This means the Commission must determine that the acquisition adjustment provides benefits to ratepayers and must determine the reasonable value of those benefits. The utility must affirmatively demonstrate that the acquisition itself has resulted in ratepayer benefits greater than the acquisition costs. The ALJ believed that Midwest had demonstrated savings of approximately $1.4 million. Because those savings would result in net positive benefits to ratepayers, the ALJ recommended that the Company recover the acquisition costs. (emphasis added)

Midwest Gas, RUD-OAG, DPS and the ALJ all agree that Midwest must affirmatively demonstrate net benefits to the ratepayer before the company can recover the acquisition cost. This is succinctly stated above by the ALJ.

This is the only reasonable standard for the Commission to use in determining prudency. Minn Stat. § 216B.16.

1. Cost of Capital Savings

Midwest claimed the acquisition provided ratepayer savings because Midwest's current cost of capital is lower than the costs North Central Public Service would have experienced, absent the merger. The Company compared its test year weighted cost of debt to an estimated 1990 North Central cost of debt. The 1990 North Central estimate was based on North Central's actual 1985 capital structure, which included a 65.8% common equity ratio. The Company's long-term debt cost was based on the proportion of North Central's to Iowa Public Service's long-term debt cost in 1985. Midwest used its proposed 12.5% return on equity to estimate 1990 North Central cost of capital. After comparing North Central's projected test year cost of capital with Midwest's 1990 cost of capital, Midwest claimed savings of $1,514,805.

The Department and the RUD-OAG agreed with the Company's basic approach to quantifying cost of capital savings but challenged the use of the 65.8% common equity included in North Central's 1985 capital structure. Both argued that the Commission had not considered nor approved a North Central capital structure with 65.8% equity and likely would not have approved such a ratio had North Central filed a rate case. The Department argued that a savings estimate should be based on rates paid by ratepayers prior to the acquisition, and that the Commission had imputed a capital structure including 56.9% common equity in North Central's last rate case. The RUD-OAG pointed out that in a number of electric rate cases since 1985, the Commission had imputed an equity ratio

[8] The ALJ cited In the Matter of the Petition of Inter-City Gas Corporation for Authority to Change its Schedule of Rates for Gas Service in Minnesota, Docket No. G-007/83-317, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (April 10, 1984).

of 45% or less. The RUD-OAG argued that it was likely the Commission would have adopted a 45% equity ratio if North Central still existed and filed a rate case in 1990.

The ALJ stated that it was most reasonable to use the equity ratio approved by the Commission in North Central's last rate case, since rates paid by ratepayers prior to the acquisition would be based on that ratio. The ALJ recommended that the Department's calculation of cost of capital savings be adopted.

The Commission agrees with the parties and the ALJ that the calculation methodology proposed by Midwest provides a reasonable means of estimating the cost of capital savings resulting from the acquisition of North Central Public Service. It is <u>reasonable to compare the Company's test year weighted cost of debt to an estimated 1990 North Central cost of debt, in order to determine if ratepayers have achieved cost of capital savings through the acquisition.</u> (emphasis added) The Commission will next determine the appropriate equity ratio to use for a projected North Central rate case in 1990.

In general rate cases, the Commission must closely scrutinize the level of common equity to ensure that ratepayers are not required to pay an unnecessarily high cost of capital. Because the percentage of common equity is, to some extent, within a utility's control and is typically the highest cost capital, the Commission requires that utilities clearly demonstrate that their equity level is reasonable. The Commission notes that, in North Central's last rate case and other recent cases, it has imputed a lower equity ratio than actually exists, in order to balance more properly investor and ratepayer interests. The Commission finds that the Company has not demonstrated that its proposed equity ratio of 65.8%, based upon North Central's pre-acquisition capital structure, would be found reasonable for an existing North Central Public Service.

The Commission also disagrees with the Department and the ALJ that the equity ratio approved in North Central's last rate case provides a sound base for the calculation of savings, when compared to Midwest's test year capital structure. There has not been a showing that an equity ratio found to be reasonable in the 1983 rate case would necessarily be reasonable in a 1990 case. The Commission finds that an equity ratio of 56.9% would result in an excessive cost of capital. A lower equity ratio is necessary to establish North Central's projected 1990 cost of capital and the related acquisition savings.

The Commission agrees with the RUD-OAG that it has imputed equity ratios of 45% or lower in a number of cases since 1985, when it determined that a higher equity could result in ratepayers paying an unnecessarily high cost of capital. The Commission notes, however, that the majority of these cases involved electric, or primarily electric, utilities considerably larger than North Central. Differences in the gas and electric industries, in company size, in the residential versus commercial/industrial nature of the customer base, as well as in capital structure, would support an equity ratio for North Central greater than the 45%

imputed in cases involving large electric utilities. In its discussion, Midwest quoted the January, 1991 C.A. Turner Utility Reports, which showed that electric companies nationwide average an equity ratio of 41% while gas utilities average 49%. The Commission finds that an equity ratio of 49%, equal to the nationwide average of gas utilities, will provide the most appropriate base for the calculation of cost of capital savings. The Commission will impute an equity ratio of 49% for an estimated 1990 North Central rate case, in order to calculate cost of capital savings from the North Central acquisition.

Once the equity ratio is established, the Commission must determine how the portion of capital reduced from pre-acquisition equity ratios (from 65.8% to 49%) will be characterized. One possibility would be to include the difference in capital as additional long-term debt; the other possibility would be to include the difference as short-term debt at a cost equal to the prime interest rate. The Commission, in its determination of capital structure discussed later in this Order, has removed short-term debt from the capital structure calculation. Similarly, in the calculation of cost of capital savings, the Commission will not apply the reduction in equity ratio to short-term debt, but will include it as additional long-term debt. The Commission adopts a projected 1990 capital structure for North Central of 49% equity and 51% long-term debt for the purpose of calculating cost of capital savings.

Based on the capital structure approved above, the Commission finds that the acquisition of North Central has resulted in cost of capital savings of $777,621. The Commission will allow Midwest to include the $233,808 annual amortization of the acquisition cost in test year operating expenses and will allow the Company to include an acquisition adjustment in rate base that results in a test year revenue requirement impact equal to the remaining savings of $543,813.

2. Materials and Supplies

Midwest Gas claimed that savings of $27,560 occurred in the test year because the Company's centralized purchasing resulted in lower unit prices for materials and supplies than would have been available to North Central. Neither the Department nor the RUD-OAG opposed the inclusion of this amount in the test year acquisition savings. The ALJ also concurred with the Company's proposed savings.

The Commission agrees with the parties and the ALJ that Midwest has demonstrated savings in purchasing materials and supplies at less than the costs that would have been incurred by North Central. The Commission will allow Midwest to include an acquisition adjustment in rate base that results in a test year revenue requirement impact equal to the savings of $27,560.

3. General and Administrative Expenses

Midwest Gas estimated acquisition savings in general and administrative (G & A) expenses by averaging G & A expenses for the last two years of North Central's operations (1984-5), inflating that average to 1990 dollars using the GNP implicit price deflator, and comparing that average to the 1989-90 average for Midwest Gas - Minnesota. The inflated North Central average exceeded the 1989-90 Midwest Gas average by $232,560. Midwest proposed acquisition savings in this amount.

Midwest presented several other computational methods to support its proposed G & A acquisition savings. The Company analyzed four of the individual areas of G & A expense: salaries, building expenses, excess general liability expense and health insurance. Midwest attempted to quantify acquisition savings by inflating actual 1984 or 1985 expenditures of North Central in these accounts to 1990 values and comparing those values to actual 1990 expenditures of Midwest Gas. The differences identified in this manner totalled $516,124.

Midwest provided two additional comparisons to support its claim of reduced G & A expenses due to the acquisition. In one, the Company compared 1984 spending of North Central and 1990 spending of Midwest Gas to the average spending of a group of comparable companies in those years. In the other, the Company argued that Midwest's spending is proportionately less than North Central's would have been, due to economies of scale.

The Department and RUD-OAG both argued that the Company's main analysis of G & A expense savings was inappropriate because expenses for the 1985 base year were significantly higher than normal. After eliminating 1985 data, the separate analyses performed by the Department and the RUD-OAG indicate no savings when comparing Midwest 1990 G & A expenditures to the pre-merger expenditures of North Central.

The Commission agrees with the ALJ that the Company has failed to prove that $232,560 in G & A savings resulted from the acquisition. The Company has not adequately supported its methodology for arriving at this figure. Neither has the Company successfully repudiated the alternative comparisons of the Department and RUD-OAG, which indicate potential savings far lower than those claimed by Midwest. All the comparisons proposed by the Company require unsupported assumptions to be made in projecting 1990 North Central G & A expenses. The Commission finds that these comparisons are insufficient to establish a reasonable and quantifiable savings amount. <u>The Commission will not allow an acquisition adjustment for the Company's proposed G & A expense savings.</u> (emphasis added)

4. Gas Cost Savings

Midwest Gas claimed that Minnesota gas customers realize annual gas cost savings of $969,429 due to the acquisition of North Central. The Company identified two general areas of savings: $304,429 in annual savings from Midwest's ability to conduct timely zone transfers of gas, and $665,000 in annual benefits related to an interconnection with the Natural Gas Pipeline Company.

Midwest claimed that its geographical diversity allowed it to respond to peak demand needs in one operating zone by transferring spot gas from other Midwest operating zones. The Company claimed that the costs of these transfers were less than the costs of the transfer options that would have been available to North Central (purchasing storage, operating peak shaving facilities, or taking penalty gas). The Company identified specific zone transfers resulting in savings of $304,000 in 1989 and $90,820 in 1990. Midwest argued that the $304,000 was more representative of ratepayers' annual savings because 1989 was a "weather normal" year, while 1990 weather in the Minnesota service territory was 21% warmer than normal.

In addition, Midwest contended that its connection of Des Moines, Iowa to a Natural Gas Pipeline Company (NGPC) line created competition between NGPC and Northern Natural Gas (NNG). Midwest claimed that this competition and the related negotiations between Midwest and NNG resulted in direct, recurring benefits of $665,000 to Midwest's Minnesota customers.

Midwest argued that the benefits negotiated have not been extended to other gas utilities in Minnesota and are the direct result of Midwest's actions to establish competition in the Des Moines market. The Company contended that these benefits would not have been available to a current North Central utility, without a significant offsetting investment in facilities or fuel costs.

The Department claimed that savings on specific peak demand transfers should be considered too speculative to support the acquisition adjustment. The RUD-OAG accepted the Company's 1990 test year savings calculation of $90,800 for zone transfers used to offset peak demand. The RUD-OAG argued that the Company's proposed inclusion of non-test year (1989) savings was not warranted even if 1989 was a more "weather normal" year than 1990. The ALJ agreed with the position of the RUD-OAG.

The Department supported $584,000 of the Company's claimed savings of $665,000 related to the interconnection with the Natural Gas Pipeline Company. The RUD-OAG agreed that some savings to Minnesota ratepayers will result from the Iowa pipeline and accepted $223,000 of Midwest's claimed $665,000 interconnection savings. The ALJ concurred with the RUD-OAG.

In order to recover acquisition costs, a utility must show that it has generated benefits for ratepayers, that those benefits are quantifiable, and that those benefits would not have been realized by the ratepayers without the acquisition. The Commission finds that Midwest has not met its burden of demonstrating that its zone transfers will provide a continuing pattern of ratepayer savings or why these transactions should be isolated from other purchasing activity. Neither has Midwest proven that the savings and concessions received from its supplier were not part of a normal business pattern unrelated to the competitive threat created by the Iowa pipeline, or that an ongoing North Central would not have obtained similar benefits in the absence of an acquisition. The Commission finds that the gas cost savings claimed by Midwest are simply too speculative to ensure ongoing ratepayer benefits. The Commission will not allow an acquisition adjustment for these amounts.

Thus, the Commission's decision on the four areas of savings requested by Midwest result in the following savings for ratepayers.

Cost of Capital Savings	**$543,813**
Materials & Supplies Savings	**27,560**
G & A Expense Savings	**- 0 -**
Gas Costs Savings	**- 0 -**
Total	**$571,373**

Thus, the findings of the Commission of cost savings equalling $571,373 should be compared to the revenue impact of the acquisition $1,249,768. In doing so, the Commission savings to ratepayers of $571,373 do not exceed acquisition costs of $1,249,768.

The majority decision of the Commission is arbitrary and capricious in that the commissioners did not consider the evidence of the rate case;

1. **All parties including Midwest Gas agreed the company must demonstrate net savings to ratepayers.**

2. **ALJ recommended that the company must demonstrate savings that exceed costs based on Intercity Gas Docket No. G-007/GR-83-317.**

Savings of $571,373 do not exceed $1,249,768 in costs to ratepayers, therefore, net savings do not exist and the recovery of acquisition costs should be denied.

Signed ________________________ ________________________
Darrel L. Peterson Cynthia A. Kitlinski
Chair Commissioner

Date: ________________________